EXHIBIT B

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Decision 07-07-027 July 26, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 06-05-027 (Filed May 25, 2006)

OPINION ADOPTING TARIFFS AND STANDARD CONTRACTS FOR WATER, WASTEWATER AND OTHER CUSTOMERS TO SELL ELECTRICITY GENERATED FROM RPS-ELIGIBLE RENEWABLE RESOURCES TO ELECTRICAL CORPORATIONS

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1. Summary

California electrical corporations must make a tariff available to public water and wastewater agencies for the purchase of electricity generated from certain electric generation facilities powered by renewable resources. They may make the terms of the tariff available in the form of a standard contract.[1]

Today's decision adopts tariffs and standard contracts for the purchase of this electricity from water and wastewater customers. The result is a simple and streamlined mechanism for certain generators to sell electricity to the utility without complex negotiations and delays. We also adopt similar tariffs and standard contracts for the purchase of electricity from other customers on the same simple and streamlined basis. Each electrical corporation shall make a compliance filing within seven days of the date this order is mailed.

Two respondents are dismissed (Avista Utilities and New West Energy).[2] The proceeding remains open to address limited other matters stated in the

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[1] Pub. Util. Code § 399.20. (Assembly Bill (AB) 1969 (Yee) Stats. 2006, Chapter 731.) All code references are to the Public Utilities Code unless noted otherwise.

[2] The respondents to this proceeding were named in Appendix A to the May 25, 2006 Order Instituting Rulemaking. They are in the categories of large utilities, small and multi-jurisdictional utilities (SMJUs), registered electric service providers (ESPs), and prospective community choice aggregators. Avista Utilities is in the category of SMJU, and New West Energy in the category of ESP.

August 21, 2006 Scoping Memo and Ruling, and June 15, 2007 Amended Scoping Memo and Ruling.

2. Background

Today's decision has its roots in the 1973 oil embargo, nearly 35 years ago. California responded to the significant disruption and great uncertainty by developing many innovative programs to promote conservation and alternative generation. By 1979, the Commission had determined it was just and reasonable, along with promoting conservation, efficiency and equity, to purchase electricity generated by cogenerators and small power producers using standard offers priced at the buying utility's full avoided cost. This included purchases of electricity from the same types of renewable resources at issue here.[3]

A successful program evolved in California during the 1980s, and existed in various ways until electric market restructuring in the 1990s. As restructured, California anticipated that market forces would determine the type of resources to be built, by whom, where and when.

The energy crisis of 2000-2001 forced California to reassess its reliance solely on the market. It provided an opportunity to reexamine how to optimally balance supply and demand, and reconsider the range of reasonable ways to promote the development of alternative supplies. As part of that effort, in 2002 the Commission initiated the current program of procuring electricity generated by renewable resources.[4]

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[3] This approach was subsequently adopted and implemented as a national standard by the Federal Energy Regulatory Commission (FERC) in its implementation of the Public Utility Regulatory Policies Act (PURPA).

[4] Decision (D.) 02-10-062 in Rulemaking (R.) 01-10-024.

In 2003, the Renewables Portfolio Standard (RPS) Program was added to the Public Utilities Code. The RPS Program requires that each California electrical corporation or retail seller, with limited exception, procure a minimum quantity of electricity each year from eligible renewable energy resources. Further, it specifies that the minimum quantity increase by at least 1% each year, and reach 20% of total retail sales by no later than 2010.[5]

In 2006, the Legislature found that the development of new energy supplies was not keeping pace with the state's increasing demand. It also found that the development of new renewable resources had been slower than anticipated, and was limited by existing transmission constraints. It determined that public water and wastewater facilities are strategically located and interconnected in a manner that optimizes delivery to load.

The Legislature responded to these concerns and opportunities by adding § 399.20 to the Public Utilities Code (AB 1969). Under this new law, each electrical corporation must establish a tariff for the purchase of RPS-generated electricity from certain water and wastewater customers, and purchase that electricity at a market price determined by the Commission. The electricity applies toward the electrical corporation's RPS Program annual targets. The tariff must be made available until the combined statewide cumulative rated capacity of eligible sellers reaches 250 megawatts (MW), with each buyer required to offer service until it meets its proportionate share of the 250 MW based on the ratio of its peak demand to total statewide peak demand.

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[5] § 399.11 *et seq.* (Senate Bill (SB) 1078 in 2002, as amended by SB 107 in 2006.)

On March 12, 2007, the assigned Commissioner filed an amended Scoping Memo and Ruling regarding implementation of § 399.20. The ruling required each respondent electrical corporation to file a proposed tariff, a proposed standard contract (if it elected to offer one), and address various implementation and policy questions.

On or about April 11, 2007, proposals were filed by seven electrical corporations: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), PacifiCorp, Sierra Pacific Power Company (Sierra), Bear Valley Electric Service Division (BVES - a division of Golden State Water Company), and Mountain Utilities (MU). Also on or about April 11, 2007, notice of the proposals was provided by each electrical corporation to potentially interested water, wastewater and other customers.

On or about May 2, 2007, comments were filed by Inland Empire Utilities Agency (IEUA), the Commission's Division of Ratepayer Advocates (DRA), the Center for Energy Efficiency and Renewable Technologies (CEERT), and jointly by Sustainable Conservation and RCM International (RCM). On or about May 9, 2007, reply comments were filed by SCE, PG&E, PacifiCorp, and jointly by Sustainable Conservation and RCM.

Motions for evidentiary hearings were due by May 14, 2007. No motions were filed. By ruling dated May 29, 2007, respondents were directed to file limited additional information, and a workshop was scheduled.

On June 4, 2007, PG&E filed and served an amendment to its initial proposal (now including a proposed tariff).[6] A workshop was held on June 5, 2007, at which respondents and parties addressed issues identified in the ruling and raised by parties.[7]

On June 13, 2007, PacifiCorp amended its proposal (to include its previously referenced proposed standard contract in the record). Also on June 13, 2007, SCE filed responses to inquiries from the Administrative Law Judge (ALJ) in two subject areas (capacity allocations; standard terms and conditions). On June 22, 2007, SCE filed certain items regarding its Biomass Program.

3. Water and Wastewater Customers

Our approach is consistent with applicable guiding principles employed elsewhere in the RPS Program, including those used in reaching our decisions on the RPS reporting and compliance methodology. (D.06-10-050, pp. 6-9.) For example, the adopted tariff must: (a) comply with the underlying legislation; (b) be consistent with prior decisions; and (c) be fair. Further, the approach must apply equally to all electrical corporations, absent reasons to apply differences. We also prefer a "simpler is better" approach. We opt for simplicity where we can, unless there are reasons or details that require complexity.

The Amended Scoping Memo required the filing of proposals and identified limited implementation issues. We first address tariff and standard

[6] PG&E had previously proposed only a standard contract.

[7] Notice of the Workshop was provided beginning May 22, 2007 by electronic mail and publication in the Commission's Daily Calendar.

contract proposals, and then focus on implementation issues. We later address dismissal of two respondents.

3.1. Tariff

Each electrical corporation proposes a tariff to comply with obligations under § 399.20. The proposals are the same or largely similar. We approve each utility's proposed tariff subject to limited, specific amendments discussed below.

Purchases made by the utility pursuant to, and consistent with, the terms and conditions of the tariff need not be submitted to the Commission by advice letter. Rather, such purchases are per se reasonable. Without such advice letters, however, we address below our need to keep informed and the procedures by which that is to be accomplished.

3.2. Standard Contract

The law provides that an "electrical corporation may make the terms of the tariff available to public water or wastewater agencies in the form of a standard contract subject to commission approval." (§ 399.20(e).) This is permissive, not required.

Sierra proposes to use only a tariff. We accept Sierra's proposal. We do so recognizing both that a standard contract is permissive, and that simplicity is generally desirable.

The other electrical corporations propose using a standard contract in addition to the tariff. The tariff provides the basics, and the standard contract provides many specifics. The tariff references the standard contract, requires its

execution,[8] and together they are one package. We approve each proposal subject to certain modifications discussed below.

We do so noting that, while the proposed tariff/standard contract package requires each seller to select limited items (e.g., term of contract), the package is otherwise on a "take it or leave it" basis. We agree with this approach. The fundamental principle here is a simple, streamlined program. A potential seller can review the tariff, standard contract and rates; perform its own analysis; and make necessary decisions (e.g., contract length, whether to sign the contract). The seller does not need to incur potentially substantial time and expense in lengthy or complex negotiations. A seller may elect to engage in negotiations, but the resulting deal would then be a bilateral or other type of contract, and outside the scope of the § 399.20 tariff/standard contract program.

3.3. Allocation of 250 MW

The law provides that:

> "Every electrical corporation shall make this tariff available to public water or wastewater agencies that own and operate an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the combined statewide cumulative rated generating capacity of those electric generation facilities equals 250 megawatts…Each electrical corporation shall only be required to offer service or contracts under this section until that electrical corporation meets its proportionate share of the 250 megawatts based on the ratio of its peak demand to the total statewide peak demand of all electrical corporations." (§ 399.20(e).)

Certain implementation questions arise.

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[8] See, for example, Special Condition 1 in SCE's proposed Schedule WATER.

3.3.1. Allocation of Shares

At the direction of the ALJ, parties met before filing their proposals to consider several issues, including whether or not they could agree to a method of determining the allocation of proportionate shares. Parties report they agreed on a general methodology. We adopt the method and its result here.

Accordingly, respondents report that each electrical corporation provided the California Energy Commission (CEC) with its system demand for retail service load (including bundled service, direct access and community choice aggregation). This was done at the California Independent System Operator (CAISO) level, and was coincident with the 2005 state peak demand.[9] The CEC used this information to allocate the 250,000 kilowatts (kW) of program capacity and report the shares back to each participating electrical corporation. The allocation is:

Electrical Corporation	Share of 2005 Coincident Peak Demand (%)	Capacity Allocation (kW)
SCE	49.538	123,844
PG&E	41.841	104,603
SDG&E	8.022	20,055
PacifiCorp	0.405	1,013
Sierra	0.162	404
BVES	0.031	77
MU	0.001	3

9 This was July 20, 2005 at 1600 (4:00 p.m.).

TOTAL	100.00	250,000

3.3.2. Updates to Allocation

Proposals vary regarding the time and manner to perform updates to the allocation. PG&E suggests revisions no more often than biennially, coincident with CEC's release of its energy demand forecast. Sierra believes its share will decline over time (since its load is growing more slowly than in the rest of the state), and expects an annual adjustment in the allocation.

We adopt the simpler approach recommended by SDG&E and PacifiCorp, wherein the allocation is updated only as needed. Because we expect the allocation to be reasonably stable, we adopt the above allocation without also including an order for a routine, periodic update. The cost of resources devoted to a constant update process would likely exceed the benefit.

As PacifiCorp notes, however, a respondent should be permitted to seek adjustment when appropriate and necessary. A utility with an interest in adjusting the allocation should employ the same methodology employed herein, using the offices of the CEC, if and as necessary, to collect data and perform the allocation. The proponent of a reallocation would then use an appropriate procedural vehicle to present its proposal and case. We expect that would be by an advice letter. All interested parties may comment on the advice letter. If submitted as a Tier 3 advice letter, Energy Division will then prepare a resolution approving, approving with modification, or rejecting the advice letter. If the situation involves disputed issues of fact or law beyond the relatively ministerial matters generally treated by advice letter, Energy Division may reject the advice letter and recommend it be resubmitted by application.

The adopted approach provides stability and cost savings, but permits updates as necessary and reasonable. As SDG&E says: "This approach will

promote simplicity, which is consistent with the view endorsed by the Commission that 'simpler is better.'" (Proposal, p. 5.)

3.3.3. Allocation Stated in Tariff

In general, we seek a simple program wherein nearly all relevant information may be found in one, or only a few, locations. The megawatt allocation is an important element of this program, and should be relatively easy to find. Because we expect the allocation to be reasonably stable, we direct each respondent to state its allocated share in its tariff. The allocation should be stated to a level of accuracy of one kilowatt, since some allocations are of only a few hundred kilowatts, or less.

3.4. Queue, Tariff Closure, Information

Parties were asked to address questions of the project queue, tariff operation, and what happens when each utility reaches it allocated share. Each respondent reasonably states its proposed processes, and each is adopted with limited explanation below.

3.4.1. Queue

First, we agree with respondents that the law is clear: the offer is on a first-come-first-served basis. (§ 399.20(e).) PG&E correctly points out that "first-come" might be interpreted to mean when: (a) the electrical corporation receives the executed standard contract or (b) the on-line date of the facility. PG&E and the majority of parties recommend using execution of the standard contract.[10]

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[10] Sierra employs a tariff, not a standard contract. In Sierra's case, the queue is in the order of a customer requesting service under the tariff. Requesting service here is the date of the request by the customer to Sierra.

We agree. This will promote an orderly process for initial subscription and financing of projects, including certainty that the output will be purchased when the project subsequently becomes operational. Execution of the contract here means when signed by the customer, since this is a standard contract made available by the utility.

The alternative (of developing the queue using on-line date) would increase the incentive for a project to come on line quickly, and stimulate competition between projects. It would also increase uncertainty and risk relative to purchase of the output. The increased uncertainty and risk may prevent the development of some otherwise reasonable projects.[11] There are, however, other ways to ensure projects are brought on line timely, which we address further below (e.g., the standard contract expires unless the project becomes operational within 18 months, or the project obtains an extension). Thus, a project queue should be maintained by each respondent based on the date of expressed interest in the tariff (Sierra), or receipt of an executed (seller-signed) standard contract.

To maintain the queue, PG&E suggests that each respondent should have the option, once all facilities whose combined capacity fills a respondent's proportionate share become operational, to periodically terminate remaining projects in the queue. We agree. This will foreclose the possibility that sellers remain in a queue indefinitely, and will promote some reasonable clarity and

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[11] For example, the developer might be uncertain whether or not the project could become operational before the full subscription of the 250 MW. This would increase project risk. Some developers may elect to place their funds elsewhere rather than take the risk of project development here with the eventual result of no sales.

certainty to existing and potentially new projects about the likelihood of their obtaining service under this tariff. When the combined capacity from sellers falls below respondent's MW allocation, projects terminate (e.g., after 10 years of a 10-year contract), or otherwise as needed, each respondent should give notice to potential customers that projects may again be subscribed under the tariff and respondent should at that time re-establish a queue.

Finally, no respondent proposes that the rank within the queue be tradable. We agree, and require that each respondent maintain the queue by individual project or proposal. In this way, the ranking in the queue is not assignable or tradable with another developer or project. Ranking within the queue should not itself have a market value. We do not intend the queue to become something that creates or eliminates value, is subject to speculative use by customers and projects, and is separately tradable for gain or loss. Respondents shall maintain the queue in a manner consistent with this intention.

3.4.2. Tariff Closure

As provided in the code, each respondent is required to offer the tariff or standard contract only until it meets its proportionate share of the 250 MW. (§ 399.20(e).) When the allocation is reached, certain obligations under the tariff cease relative to new subscribers.[12]

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[12] Parties were asked to address how and when the tariff should be suspended. On further reflection, we conclude that the tariff itself is not suspended. Rather, certain obligations under the tariff cease, and the tariff is closed to new customers. Respondents need not file an advice letter to suspend the tariff, for example, when the capacity allocation is reached, but are relieved of an obligation to purchase energy from additional projects pursuant to the § 399.20 tariff. Respondents may voluntarily elect to purchase energy from additional projects on these or other terms (e.g., see discussion regarding BVES later in this order). Projects up to the allocated capacity are per se

Footnote continued on next page

That is, the tariff is closed with respect to new customers, and respondent need neither subscribe additional customers under the tariff nor execute additional standard contracts. If a project within the allocation terminates for any reason or the total installed capacity falls below respondent's proportionate share,[13] the next project in the queue should be notified and given the option to proceed. Respondents should each use a reasonable, fair and consistent procedure as described in their proposals to maintain the queue beyond the allocated subscription (e.g., based on the date a project executes the standard contract or, for Sierra, a project seeks service under the tariff).

BVES recommends that the schedule not necessarily be closed when the utility meets its proportionate share, the share not be a fixed amount, and the utility have the option to flexibly employ its allocation to encourage additional renewable resource additions. No other utility makes this request.

We adopt BVES's recommendation for BVES, but decline to require this for other respondents. We encourage each respondent to fully use this tariff/standard contract to secure as much RPS generation as possible. We do

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reasonable. Projects beyond the capacity allocation need Commission review (e.g., by applicant submitting an advice letter). If the Commission determines that "oversubscription" has occurred and has caused, or may be foreseen to cause, a material problem (e.g., see discussion below regarding oversubscription related to qualifying facilities (QFs)), the Commission may take that into account in deciding whether to approve or reject certain advice letters.

[13] For example, a project's standard contract may terminate because the developer elects not to continue with project development, fails to become operational within 18 months (and does not obtain an extension), fails to continue to operate and sell output for a period of 12 consecutive months, or completes the term of its agreement (e.g., 10, 15 or 20 years).

not, however, introduce confusion and uncertainty in tariff administration by, for example, adopting either an open-ended or "floating" allocation. There is some risk that more generation will be developed than needed or desirable at the market price referent (MPR).[14] We seek a controlled growth of this RPS supply opportunity. We encourage respondents to file advice letters to increase their allocations, if they wish. We decline to unilaterally remove all allocations for all respondents.

3.4.3. Information

We do not require the filing of an advice letter when a respondent reaches its proportionate allocation, even though this would be one reasonably easy procedural vehicle to close the tariff, inform the Commission, and inform the public. To do so, however, could result in the filing of several advice letters by each respondent as the last few projects come and go to reach the final allocated amount.

Nevertheless, the Commission needs timely information about this program. While we do not require the filing of an advice letter, each respondent must provide information on this tariff and program when required by the Commission, including information on sellers, projects, the allocation, and the queue. We encourage respondents and staff to develop a periodic report, or a component of an existing periodic report, for the relatively routine reporting of this information.

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[14] Some observers believe this is what happened with Interim Standard Offer No. 4 (ISO 4) in the 1980s, resulting in too much QF generation before the Commission could either withdraw the availability of ISO 4, or continue the availability but at a reduced avoided cost.

3.5. Tariff Rates

3.5.1. Market Price Referent

The rate is to be determined as follows:

> "The tariff shall provide for payment for every kilowatthour of renewable energy output produced at an electric generation facility at the market price as determined by the commission pursuant to Section 399.15 for a period of 10, 15, or 20 years, as authorized by the commission." (§ 399.20(d).)

That is, the rate is to be the market price as determined by the Commission.

3.5.2. Rates Must Be Stated

Only PacifiCorp proposes to include the applicable rates in its tariff. Others propose a statement referring to applicable rates.

We adopt PacifiCorp's approach for PacifiCorp. Tariffs are typically the place one looks to find rates. Rates should generally be included with § 399.20 tariffs.

Sierra proposes use of a tariff, but without an accompanying standard contract. Sierra does not propose to include the applicable rates in its tariff. Absent use of the standard contract, we require that Sierra include the rates in its tariff.

We are persuaded by other respondents, however, to deviate from this principle in part, and we require only that they include the actual rates in their standard contract. We do this because interested persons must be able to find relevant program information, including rates, without undue burden. If not in the tariff, respondents should be required to include applicable rates in the standard contract, on the respondent's web page, or in some other venue. No particular reduction in burden is obvious from any alternative. Each requires

some effort to make the rates available in the first instance. In all cases, applicable rates must be updated as appropriate.

We generally adopt a "simpler is better" approach. We apply this principle here to authorize relatively simple tariffs for all seven respondents. For six respondents (i.e., not Sierra), the tariff will be combined with a more detailed, specific and precise standard contract. For these six respondents, the standard contract (not the tariff) will include time of use factors to differentiate the annual MPR into time periods, and other relevant price-related detail. In these cases, it is reasonable to also include the applicable rates in the standard contract, not the tariff.[15] In this way all the terms reasonably necessary to determine potential revenue from the sale are in one place.

Whether the rates are in the tariff or standard contract, changes will require Commission notification. That is, the tariffs refer to, and incorporate, the standard contract. Changes to tariffs, and items incorporated into the tariff, must be approved by the Commission. Thus, whether the rate is in the tariff or the standard contract, we expect respondents to use normal Commission procedures regarding revisions. In this case, a respondent would typically use an advice letter.

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[15] Individual items in the standard contract may contain a range of choices, from which the seller selects one. In this case, the standard contract would list the range of applicable MPR rates. If parties wish, the actual signed contract may include only the applicable rate (or rates). For example, a standard contract for a 10-year term might exclude all rates for 15- and 10-year terms. As noted below, however, the effective rate will be based on the actual year of initial commercial operation. As such, it may be necessary for the signed contract to include a range of rates correlated to the date(s) of potential initial commercial operation for the term of the contract.

Respondents argue that an advice letter requirement places an extra, unreasonable burden on them with regard to this program. We disagree. The advice letter process has always been, and continues to be, a streamlined process for respondents, parties, and the Commission. We do not foresee the MPR as being so unstable as to require a constant stream of advice letter filings. Further, an advice letter will not necessarily introduce any delay. For example, an advice letter to update a tariff based on an updated MPR can become effective upon filing.[16] An advice letter is a method to advise the Commission and the public of a change. We are not persuaded to deviate from normal Commission practice. Rather, we employ simple and streamlined ways within our protocols.

Finally, it may be argued that most prospective water and wastewater agency customers are reasonably sophisticated and need not have the rates publicly stated in the tariff or standard contract. Rather, such customers know how to locate necessary information through the utility, a web page, or otherwise.

We agree most customers here will be knowledgeable, and easily able to find information. Nonetheless, we are not convinced that a reference to the rate is adequate. A simple but complete tariff, in most cases combine with a standard contract, is an efficient and professional way to administer this program. Moreover, some potential customers may at first be less sophisticated. We also expect the fundamentals of this program to be easily understandable and researchable. Thus, we require disclosure of the applicable rate as noted above.

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[16] A Tier 1 Advice Letter can be effective on the day it is submitted. (D.07-01-024, p. 25.)

3.5.3. Unique Rates

PacifiCorp, Sierra and BVES argue for unique rates for their tariffs. They also contend it may be too costly and burdensome to develop their own MPR. Each proposes a relatively streamlined alternative.

We decline to adopt their recommendations for the reasons stated below. Rather, our MPR methodology produces a uniform, statewide MPR. We will use that result. The issue of MPRs for SMJUs is currently being considered in R.06-02-012. If we later reach a different result there, the SMJUs may file advice letters at the appropriate time to align MPRs here with those adopted later.

PacifiCorp: PacifiCorp requests that the Commission apply an alternate market price mechanism in lieu of the MPR adopted by the Commission pursuant to § 399.15. The result would likely be a rate lower than the current MPR. In particular, PacifiCorp says the rate here should be consistent with PacifiCorp's avoided cost authorized by other state jurisdictions in which PacifiCorp operates to ensure cost-effective services for PacifiCorp's ratepayers.

We disagree. As noted above, we have adopted an MPR methodology pursuant to § 399.15 which applies to all respondents. It makes no differentiation between large and small, nor single or multi-state jurisdiction. (D.04-06-015, D.05-12-042.)

We agree with PacifiCorp, however, that there should be relative harmony in outcomes between avoided costs and MPR. They are, after all, based on the same essential concept: the cost of the next increment of supply, or the cost avoided by not having to purchase the last increment of supply. We expect the results to be reasonably similar, and respondents should bring significant differences to our attention with recommendations for correction or improvement. In this case, PacifiCorp would in addition need to relate

corrections or improvements to the requirements of the MPR approach pursuant to § 399.15.

Finally, we agree with PacifiCorp that the adopted rate must ensure cost-effective services without unreasonably burdening ratepayers with excessive costs. Nonetheless, PacifiCorp presents no data on that burden, and we are not persuaded it approaches a range of unreasonableness.[17]

Sierra: Sierra does not provide specific information on its proposed rate, but its proposed tariff says it will apply the MPR as determined by the Commission. It generally argues, however, that this will be contrary to results in Nevada.

Sierra should use the MPRs adopted in Resolution E-4049, unless and until such time as determined otherwise in R.06-02-012. Just as with PacifiCorp, we are not convinced that such result would unreasonably burden its ratepayers with excessive costs.[18]

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[17] PacifiCorp's allocation here is 1,013 kW. A potential project (or projects) satisfying this allocation and delivering energy at a 60% capacity factor would deliver 5,324,328 kilowatt-hours (kWh) per year. The 2007 MPR for a 10-year contract is $0.08080/kWh. (Resolution E-4049, December 16, 2006.) PacifiCorp's proposed 2007 avoided cost here is about $0.05719/kWh. (This is a simple average of PacifiCorp's proposed on-peak and off-peak rate in its April 11, 2007 proposal, Attachment A, proposed tariff, pricing.) The difference is $0.02361/kWh. If paid this MPR, the project(s) would be paid $125,707 more than PacifiCorp's recommended avoided cost. Absent other information, we do not conclude that this outcome will unreasonably burden ratepayers with excessive costs. PacifiCorp "acknowledges that any potential rate impact may ultimately be negligible." (Reply Comments, p. 2.)

[18] PacifiCorp's allocation is 1,013 kW, and Sierra's allocation is 404 kW. If the data in the footnote above for PacifiCorp reasonably applies to Sierra, the payment above Sierra's alternative avoided would be about $50, 134. (That is $125,707 times

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BVES: BVES says the market price should be based on the MPR applicable to each utility. It reports that it made a filing in R.06-02-012 in which it requests an MPR that is approximately 15% higher than that currently applicable to the large electrical corporations. It seeks that same result here. We agree that the results should be the same. To the extent BVES prevails in R.06-02-012, the result should carry forward here. Unless and until that occurs, however, BVES shold use the uniform statewide MPR.

3.5.4. Reduction in MPR for Other Costs

PG&E proposes an administrative fee in the form of a 10% reduction in its monthly payment to the seller. In support, PG&E says its customers will incur certain costs (i.e., CAISO Scheduling Coordinator charges for being seller's Scheduling Coordinator). Further, PG&E states that its proposed § 399.20 standard contract contains only the four non-modifiable terms and conditions required in contracts used by energy service providers and community choice aggregators for RPS compliance.[19] PG&E explains that its proposed § 399.20 standard contract does not contain other standard terms and conditions mandated by the Commission for use in the RPS program, some of which PG&E contends might otherwise deter eligible sellers from this § 399.20 tariff/standard contract.[20] In recognition of these benefits to the seller as well as the costs incurred by PG&E, PG&E proposes a 10% reduction.

(404/1013).) Absent other information, we do not conclude that this would unreasonably burden ratepayers with excessive costs.

[19] PG&E cites D.06-10-019, p. 51, Conclusion of Law 19.

[20] For example, PG&E says these include, but are not limited to, not requiring that the seller (a) post a bid deposit, (b) meet certain performance requirements and provide

Footnote continued on next page

No other respondent proposes a reduction in MPR for such costs. The reduction is opposed by Sustainable Conservation, RCM, IEUA and DRA.

We decline to adopt PG&E's proposal. The legislation is clear. The rate is the "market price as determined by the commission pursuant to Section 399.15." (§ 399.20(d).) We have determined the MPR pursuant to § 399.15 in two decisions and various resolutions.[21] PG&E does not cite support for its proposal in § 399.15, our decisions or our resolutions. The reason is that such support is not there. Our MPR methodology does not include a provision for reducing the MPR for Scheduling Coordinator services or benefits provided to the seller. It is not dependent upon the standard terms and conditions. As a result, PG&E's tariff/standard contract filed by advice letter pursuant to this order shall not contain the provision that the rate "shall be reduced by a ten (10) percent administrative fee." (PG&E Proposed Purchase Power Agreement, § 2.4.)

3.5.5. Actual Commercial Operation

The proposed tariffs and standard contracts generally make clear that the applicable rate is the MPR in effect on the date the standard contract is executed. The proposed tariffs and standard contracts do not make clear, however, which MPR applies should a project suffer a delay in the date of its initial commercial operation.

For example, if a project is scheduled to begin commercial operation in December 2008, but the actual commercial operation is in January 2009, an

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performance guarantees, (b) be subject to minimum acceptable credit provisions, and (d) retain a scheduling coordinator.

[21] See, for example, D.04-06-015, D.05-12-042, Resolution E-3980, Resolution E-4049.

ambiguity currently exists regarding the applicable MPR. This ambiguity should be removed. To do so, the tariff/standard contract should specify that the applicable MPR is based on the MPR table in effect on the date the contract is signed, but the specific MPR rate within that table is based on the date of actual commercial operation, not the commercial operation date initially forecast or expected when the standard contract was signed.[22]

If the MPR increases substantially and consistently each year, the decision to tie prices to actual initial operation might give an incentive to some projects to delay initial commercial operation. The MPR, however, does not necessarily increase substantially and consistently each year. Rather, some MPRs decrease year to year.[23] Some increases are not substantial.[24] We cannot conclude that one approach is superior to the other based on a specific pattern in the current MPR. Without other information to the contrary, we generally prefer that project prices be based on actual, not forecast, operation.

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[22] SCE's proposed standard contract might be modified in § 6.2 to include the word "actual" as follows: "The Product Price …with the date of actual Initial Operation…" This would be in contrast to § 2.8 of the standard contract which refers to "expected date of Initial Operation." The term "Initial Operation" is not a defined term in Appendix F of the proposed standard contract, but respondents may add a defined term if necessary for additional clarity.

[23] For example, the 10-year MPR declines each year from 2007 to 2008, 2008 to 2009, and 2010 to 2011. The 15-year and 20-year MPRs decline from 2010 to 2011. Other years increase. (Resolution E-4049, p. 1.)

[24] For example, the 10-year MPR from 2009 to 2010 increases by only 0.06% (from $0.07060/kWh to $0.0765/kWh. (Resolution E-4049, p. 1.)

3.5.6. Time Differentiated or Annual Average MPR

IEUA points out that the proposed tariffs generally provide for compensation based on time of use (TOU) factors. IEUA says it has no objection to this as an option, but believes that the law clearly states that the output should be compensated at the flat, non-time-differentiated MPR without mandatory TOU pricing. In support, IEUA points out that biogas net metering legislation (§ 2827.96) specifically references time-differentiated compensation but no such reference is included in the legislation at issue here. IEUA recommends that the adopted tariffs/standard contracts include a choice to be made by the generator between time-differentiated compensation and a flat (non-TOU) price. With limited exception, we disagree.

The requirement here is a tariff rate at the market price determined by the Commission pursuant to § 399.15. We have adopted a methodology that determines the market price pursuant to § 399.15. We employ TOU factors as part of the application of that methodology. For example, each bid solicitation accepted by the Commission and undertaken by the large investor-owned utilities over the last several years had included payments based on TOU factors.

TOU factors are important to promote economic efficiency and equity. Economic efficiency is advanced when market participants have good information, including price information related to when a product is in demand, or not in demand. TOU factors improve the price information compared to annual average (or non-TOU) pricing. Equity is advanced when payments match the cost as reflected in the MPR, thereby avoiding over- or under-payments. TOU factors better match payments with the MPR.

Further, a very important aspect of the RPS Program is development, integration and operation of resources on a least cost-best fit (LCBF) basis. TOU factors do a better job than do annual average rates of promoting LCBF development, integration and operation. We are not persuaded by IEUA to abandon this important goal by adopting an option for non-time-differentiated rates.

We also agree with PG&E and SCE that an annual average rate would mean their ratepayers buy this electricity during the off-peak period at a price above the TOU-based off-peak price. Because PG&E and SCE need electricity the least during the off-peak hours (and SCE states it currently has extra energy during off-peak periods), they could each be forced to resell the electricity at an even lower rate, thereby incurring unreasonable remarketing costs. This would frustrate efficiency, equity and LCBF goals.

IEUA argues that the annual average, non-time differentiated price might provide reasonable incentive for the development of some projects which might otherwise not develop. We certainly agree that paying higher (rather than lower) prices always provides an incentive for project development, and in some cases that might be reasonable, although in other cases it might not. IEUA provides no estimates or data on the potential affected capacity or cost, however, and we have none to balance against resulting probable inefficiencies, inequities and deviation from LCBF. Without compelling information to the contrary, we believe the overriding goals here are efficiency, equity and LCBF.

The one exception is the smallest of the respondents. We understand that Sierra and BVES propose to apply an annual average rate, and very few kilowatts are involved. Sierra and BVES may, if they choose, apply an annual

average MPR. We authorize MU to similarly use an annual average if it chooses due to the small amount of its capacity allocation.

3.6. MW Capacity of Each Project

Respondents were asked to propose tariffs which provide for service from projects with an effective capacity of not more than 1.5 MW. If proposed at an effective capacity of not more than 1.0 MW, respondents were asked to explain.[25]

SCE and SDG&E propose tariffs for projects of not more than 1.5 MW. PG&E proposes 1.0 MW, but does not object if the limit is increased to 1.5 MW for the § 399.20 tariff/standard contract here. The somewhat larger size of 1.5 MW is consistent with the law, California's RPS goals (e.g., to achieve 20% by 2010), and is reasonable. We approved the 1.5 MW amount for these three respondents.

PacifiCorp, Sierra and BVES proposed tariffs for projects of not more than 1.0 megawatts. This is also consistent with the law. The capacity allocations for these respondents are all approximately 1.0 megawatts or less. Limitation of projects to not more than 1.0 megawatts is compatible with their allocations, and is reasonable. We approve their proposals. MU proposes 1.5 MW, but, with an allocation of only 3 kW, may employ 1.0 MW at its choice.

3.7. SGIP and Net Metering

Several programs potentially overlap. To assess this, respondents were asked to address how availability of the instant tariff would affect eligibility for,

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[25] Facilities eligible for the tariff here are those with "an effective capacity of not more than one megawatt…" (§ 399.20(b)(2).) The Commission may also approve a tariff or contract made available to "an electric generation facility that has an effective capacity of not more than 1.5 megawatts…" (§ 399.20(h).)

or payments under (a) the self-generation incentive program (SGIP) and (b) net metering programs. No respondent or party argues that participants on this tariff are, or should be, eligible for either SGIP or net metering.

We agree. We approve proposed tariffs/standard contracts which make clear that participants may not simultaneously obtain benefits from both this tariff and the SGIP, net metering programs, California Solar Initiative, or other similar programs.

3.8. Standard Terms and Conditions

The Commission adopted 14 standard terms and conditions (STCs) for RPS contracts.[26] Respondents were asked to address the relevance, if any, of these 14 STCs to the tariff/ standard contract here. Respondents report they have used some, but not all, of the STCs. Of those employed, some are proposed using the exact language adopted by the Commission and others use simplified wording.

We are generally convinced by respondents that not all of the STCs should apply here, and some may be simplified. We adopt the proposals, but with limited modifications noted below.

Not all STCs apply here. For example, an explicit STC regarding Commission approval is unnecessary since this program is by tariff, and purchases under the tariff are per se reasonable. A STC regarding supplemental energy payments (SEPs) is unnecessary because this program does not contemplate projects seeking additional funds from the SEP program. A STC

[26] See § 399.14(a)(2)(D). STCs were adopted by the Commission in D.04-06-014, and modified by D.07-02-011 and D.07-05-057.

regarding performance standards and requirements is generally unnecessary since this is a pay for performance program (with no pay for non-performance). The credit term STC is generally unnecessary due to small project sizes (less than 1.5 MW) and the nature of these customers (water and wastewater public agencies).

Other STCs apply. These include: (a) definition and ownership of renewable energy credits (now called Green Attributes), (b) eligibility, (c) assignment, (d) applicable law, (e) confidentiality, (f) contract term, (g) non-performance or termination penalties and default provisions, and (h) contract modifications. For example, we found the first four of these STCs apply in all RPS contracts (whether with large utilities, small utilities, multi-jurisdictional utilities, energy service providers, or community choice aggregators). These four are necessary to ensure that RPS buyers and sellers are trading the same item, with the same environmental attributes, and with the same legal requirements related to basic elements. (D.06-10-019, pp. 32-33.) We adopt the same principles here for the same reasons.

Respondents also propose related or simplified language for the last four STCs listed above. We are convinced by parties that in some cases the wording in the tariff/standard contract may be simplified, but in all cases respondents represent that the proposals are the same or materially equivalent. We adopt the proposals, except as noted below.

a. Green Attributes: Our treatment of renewable energy credits (RECs) was originally in our defined term "Environmental Attributes." We changed that term to "Green Attributes," and later adopted an unopposed petition for modification to correct an error. (D.07-02-011, D.07-05-057.) PG&E's proposed language tracks the language from D.07-02-011. PG&E states that it will

incorporate changes to correct the error consistent with the changes adopted in D.07-05-057. We agree with PG&E that it should do so. The other utilities largely represent that their proposed language is materially the same as the Commission's STC. As the REC market is formed, it is particularly important that this term be standardized, and precisely the same language be used. Thus, in all cases the adopted language should be precisely the same as adopted in D.07-02-011, and as corrected in D.07-05-057.

b. Eligibility: This term essentially requires that (i) the plant qualifies as an Eligible Renewable Energy Resource (ERR) and (ii) the output qualifies under the California RPS Program. Regarding the first element, SCE and SDG&E propose language which requires the plant be an ERR. This is reasonable and we adopt their proposal.[27] Regarding the second element, SCE and SDG&E do not require that the output qualifies under the RPS program. Rather, they rely on the output as qualifying under the terms of being a QF.[28] While the RPS and QF programs are related, RPS eligibility is determined by the CEC, and QF eligibility is determined by the FERC. There may be differences. SCE and SDG&E do not draw a sufficiently convincing link between QF and RPS output at this time. Thus, SCE and SDG&E must employ language that more closely conforms to the Commission's adopted STC regarding the RPS program.

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[27] This is their proposed Appendix C: "Producer's Warranty that the Renewable Generating Facility Is and Will Continue to be an 'Eligible Renewable Resource' Pursuant to Section 399.11 et seq. of the California Public Utilities Code ('EER Warranty')."

[28] This is their proposed Appendix D: "Producer's Warranty that the Renewable Generating Facility Is and Will Continue to be a 'Qualifying Facility' Pursuant to the Policies and Practices of the Federal Energy Regulatory Commission ('QF Warranty')."

PG&E's proposed language is materially the same as that in the Commission's adopted STC (D.04-06-014, Attachment A, p. A-10.) It includes references to both ERR and the RPS Program, and should be adopted.

Other respondents represent that their language is materially the same. In all cases the resulting language should be the same or materially the same as adopted in D.04-06-014.

c. Assignment: SCE and SDG&E propose simplified language which is more restrictive than the term adopted by the Commission. No party objects. We adopt their proposal.

PG&E proposes the same language as previously adopted by the Commission, and it is adopted here. PacifiCorp and BVES represent their language as materially equivalent and is adopted. In all cases the resulting language should be the same or materially the same as adopted in D.04-06-014.

Sierra has no similar provision since its service is by tariff and is not assignable. Sierra's proposal is adopted.

d. Applicable Law: In the document filed June 13, 2007, parties identify the Commission-adopted term as composed of two sentences. With regard to the first sentence, PG&E proposes to adopt the exact language.[29] SCE, SDG&E, PacifiCorp and BVES state that their proposed language is materially equivalent to that in the Commission-adopted STC. The proposals are adopted with regard to the first sentence.

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[29] The Commission adopted an item in the Edison Electric Institute model contract with a specific modification. Parties represent here that the first sentence, as modified, is: "This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law."

Regarding the second sentence, the proposals of SCE, SDG&E, PacifiCorp and BVES do not include the Commission-adopted language, which is: "Each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement." PG&E proposes an alternate: "To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement." We adopt the proposal of PG&E as a non-substantive clarification. Moreover, to the extent enforceable, we expect parties to waive a jury trial and, therefore, require the other utilities to include PG&E's language.

Sierra has no similar provision. We agree that none is necessary with respect to the first sentence. That is, Sierra's proposal is to implement this service by tariff, and the tariff is authorized by the California Commission. The transaction under the tariff is therefore subject to California law. To the extent enforceable, however, we expect parties to waive a jury trial. Thus, Sierra must include the second sentence.

e. Confidentiality: Each respondent reports it has no provision similar to the Commission-adopted STC. Rather, the price term is settled and public, as are at the terms in the tariff and related standard contract, and thereby nothing needs to be sealed from public inspection. We adopt this proposal.

SCE, SDG&E, and BVES propose including a related term authorizing respondent to release to the CEC and/or Commission certain information regarding the project. This was added by recent legislation, and addressed by the Commission. (Added by SB 107, § 399.14(a)(2)(D), discussed in D.07-02-011.) We adopt this language, and direct others to include similar language to the extent not already proposed.

f. Contract Term: Each respondent proposes including a contract term that is materially the same as the Commission-adopted STC with regard to delivery for periods of 10, 15 or 20 years. Respondents do not generally include a provision for non-standard delivery, although PacifiCorp states it has no objection to contracting for less than 10 years.

The legislation specifically provides that the "tariff shall provide for payment... for a period of 10, 15, or 20 years, as authorized by the commission." (§ 399.20(d).) In the interests of the tariff being relatively simple and parallel with the statute, we adopt respondents' proposals. We do not necessarily read the legislation as limiting the tariff to only these three time periods, however. We endorse PacifiCorp's openness to contracting for other contract terms, and we encourage all respondents to be open to similar opportunities. We do not, however, require the tariff/standard contract to include a contract term provision for other than 10, 15 or 20 years.

g. Non-performance: Respondents, except Sierra, each include terms related to non-performance, termination penalties and default provisions, even if not using the precise language in the Commission-adopted STC. These proposals are reasonable and adopted.

Sierra has no similar provision since its proposal is simply to pay for delivered electricity pursuant to tariff. Sierra's proposal is reasonable and is adopted.

SCE and SDG&E propose an option to terminate the agreement on the 61st day after written notice of certain events. This is reasonable and is adopted.

PG&E proposes that it be entitled to terminate the agreement if the seller has not sold or delivered energy to PG&E for a period of 12 consecutive months. PG&E's proposal is reasonable and is adopted.

Moreover, PG&E's 12 consecutive month term should be employed by all respondents. Such term is complementary to, and does not conflict with, earlier termination based on the written notification proposed by SCE and SDG&E. Where appropriately used, it will ensure that the queue is reopened to another project. This will advance California's goals for development of reasonable RPS resources. Thus, we direct each respondent to include a provision entitling buyer to terminate the agreement if seller has not sold or delivered energy to the buyer for a period of 12 consecutive months. We expect each respondent to use this term reasonably.

h. Contract Modifications: Respondents, except Sierra, each include a provision for the same or simplified language regarding this Commission-adopted STC. The proposals are reasonable and are accepted.

Sierra has no similar provision since its offer is by tariff. Sierra's proposal is reasonable and is adopted.

3.9. Full Buy/Sell, Sale of Excess, RECs

3.9.1. Full Buy/Sell and RECs

Respondents, except PG&E, propose that the tariff/standard contract provide that the seller shall sell its entire RPS-generated output to the buyer. Coincident with the sale, the buyer acquires all of the applicable RECs. This is based on a plain reading of the law. In particular:

> "The tariff shall provide for payment for every kilowatthour of renewable energy output produced at an electric generation facility…" (§ 399.20(d).)

> "Every kilowatthour of renewable energy output produced by the electric generation facility shall count toward the electrical corporation's renewable portfolio standard annual procurement targets..." (§ 399.20 (f).)

> "The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement..." (§ 399.20(g).)

That is, a respondent must pay for every kilowatthour produced, and every kilowatthour produced counts toward respondent's annual procurement target (APT) and resource adequacy requirement. A direct and straightforward application of these provisions is that (a) the customer sells the entire output from its RPS generation facility to the utility, (b) the entire output of the RPS generation facility is purchased by the utility and therefore qualifies to count toward the utility's APT and resource adequacy requirements, (c) the RECs associated with the output are acquired by the utility upon the purchase of the output, and (d) the utility sells to the customer all the electricity needed to satisfy the customer's demand. This is known as "buy all/sell all" or "full buy/sell." This is a reasonable reading of the law, can be implemented and administered, and is adopted, subject to election by the seller as further explained below.

3.9.2. Sale of Excess and RECs

PG&E has another reading. PG&E asserts that the references in §§ 399.20(d) and (f) to "every kilowatthour…produced" are best understood to mean generation that is exported to the grid. PG&E supports this by pointing to the Legislature's finding and declaration that:

> "Renewable energy produced at public water and wastewater facilities will reduce the demand for the production of

> nonrenewable energy needed to serve water-related electricity demand."[30]

PG&E says this shows legislative intent to reduced demand for purchases from the utility by using on-site facilities to serve on-site demand. As a practical consideration, PG&E asserts that sellers will have little or no incentive to enter into contracts for the sale of their generation at a market rate if then required to repurchase the same generation to serve their own on-site needs but at a much higher retail rate.

As a result, PG&E proposes to pay for all generation exported to the utility grid and not used to offset the seller's own usage. This is "excess" generation, or generation net of the seller's own use. PG&E also proposes that, consistent with earlier Commission decisions, output of the generator that is used on the seller's side of the meter to offset simultaneous load (which is therefore not exported to the grid and is not compensated under the tariff/standard contract) will not count toward PG&E's APT. Similarly, PG&E will acquire only the RECs associated with the energy it purchases. The seller will retain the RECs for the electricity it uses itself and does not sell.31

Sustainable Conservation, RCM and California Farm Bureau Federation support PG&E's interpretation. PG&E's interpretation is a reasonable reading of

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[30] AB 1969, Section 1, paragraph (g), attached to March 12, 2007 Amended Scoping Memo and Ruling.

[31] PG&E's April 11, 2007 Proposal, p. 7. The standard contracts for full buy/sell and excess sales must ensure that metering is consistent with CEC RPS accounting requirements in order to accurately track renewable energy.

the law, can be implemented and administered, and is adopted for PG&E, subject to election by the seller as explained further below.

3.9.3. Seller Has Option

We seek to facilitate reasonable development of RPS resources. The tariff/standard contract approach here has potential to be an efficient and effective tool in promoting this goal.

Either reading of the law regarding the purchase obligation is reasonable, may be implemented in a workable fashion, and is in the context of a program limited to an aggregate of only 250 MW. Providing an opportunity for both approaches will permit gathering important information regarding the economics of, and market response to, full buy/sell versus excess sales.

We are persuaded by PG&E that sellers will have little incentive to enter into contracts for the sale of their generation at a market rate if then required to buy back that same generation to serve their own on-site needs at a much higher retail rate. Further, to the extent true in PG&E's service territory, it will also be true in the service territory of other utilities.

We are also persuaded by Sustainable Conservation and RCM that the seller's decision on how small or large to make the generation facility may be influenced, if not driven, by the choice of full buy/sell or excess sales. We must establish the right framework and incentives for the proper sizing of facilities, while at the same time providing equitable treatment to customers, ratepayers and stakeholders.

We note in this context that proper sizing of facilities should be based on the economics, consistent with the state's energy goals, including RPS Program goals. To qualify, a facility must be sized to offset part or all of the customer's

electricity demand. (§ 399.20(b)(3).) The qualification is not that the facility offset part or all of, and no more than, the customer's electricity demand.

We do not interpret § 399.20(b)(3) as an additional size limitation beyond the 1.5 MW limit per facility. (§ 399.20(h).) Rather, we see it as language that supports legislative intent to encourage water/wastewater customers to be electrically self-sufficient, as indicated in Section 1(g) of AB 1969 which states: "Renewable energy produced at public water and wastewater facilities will reduce the demand for the production of nonrenewable energy needed to serve water-related electricity demand."

However, it is clear that this is not the only goal of the legislation. Specifically, Section 1(f) of AB 1969 emphasizes the opportunities these facilities provide to export renewable power to load centers. Given this objective, interpreting § 399.20(b)(3) as an additional size limitation could undermine the effectiveness of the statute in motivating facilities to fully exploit reasonable onsite resource potential, which in some circumstances may exceed energy needs.

The MPR, to the extent reasonably the same as the avoided/incremental cost, gives the right price signal for future investment. When paid to buy the full output of the generation facility, that MPR provides the right price signal and compensation from the perspective of economic efficiency. On the other hand, retail rates do not always match avoided/incremental costs. Nevertheless, retail rates are a real cost incurred by the customer, and these costs are incurred or avoided by that customer through marginal purchases. It is equitable to allow the customer to offset some or all of the customer's own load with self-generation before addressing economy-wide issues of efficiency.

Therefore, we require PG&E, SCE and SDG&E to offer at the customer's option the choice of either full buy/sell or excess sales. That is, just as the customer may make selections in the tariff/standard contract for limited other items (e.g., contract term, initial operation date), the customer here may select either full buy/sell or excess sales. We do not require this of the smaller utilities since their obligations are each approximately 1.0 MW or less, and we think the additional burden of developing, offering and administering this option would likely outweigh the benefit. That is, smaller utilities need only offer full buy/sell, but may, if they choose, also offer an excess sales option to be exercised by the seller.

3.10. Initial Operation and Interconnection

3.10.1. Initial Operation

Respondents' standard contracts propose a period of time during which the project must be completed and begin commercial operations. If the project does not come on line within that time, the contract is subject to termination.

We endorse the concept of a time period leading to potential contract termination. This presents an orderly process for both developer and utility in which to frame future events and plans. It also opens the queue to other projects if and when a project in the queue is subject to contract termination.

Respondents propose different time periods and mechanics to accomplish contract termination. For example, SCE and SDG&E require that the expected initial operation be within nine months of the date of the agreement.[32] BVES

[32] April 11, 2007 Proposal of SCE, Schedule WATER, § 2.8; April 11, 2007 Proposal of SDG&E, Schedule WATER, § 2.9.

requires expected initial operation within 12 months of the date of the agreement.[33] Failure to achieve expected initial operation places the generating facility out of compliance with the agreement, and permits the utility to provide written notice of the intent to terminate within 61 days of the date of the notice.[34] PG&E's standard contract entitles PG&E to terminate the agreement if the facility has not achieved commercial operation within 18 months of the execution date of the agreement.[35]

Absent reasons otherwise, we generally seek uniformity and simplicity in this program. Respondents present no compelling reasons to support differences between their proposals here, and we see no reason that the timeframes should be different. Therefore, we adopt a uniform timeframe.

Once an agreement is signed (or service is requested under the tariff) there may be several steps before a project becomes operational.[36] Given these steps for many if not most projects, it is likely that initial project operation will in many cases be later than nine months after contract execution. In fact, it may take more than 18 months for many projects to be completed and commercially operational. Nonetheless, we adopt 18 months, the longest proposal made here.

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[33] April 13, 2007 proposal of BVES, Agreement, § 2.8.

[34] See § 4.2(c) in SCE, SDG&E and BVES proposed agreements.

[35] June 4, 2007 Amendment to Proposal of PG&E, Power Purchase Agreement, § 10.2(a).

[36] For example, based on years of experience with applications for a Certificate of Public Convenience and Necessity and other proceedings, the Commission knows that these might include: final engineering, final environmental approvals, final agency approvals, final securing of finances, ordering of parts and equipment, site preparation, construction, and testing.

Each respondent should include a period of 18 months in its tariff or standard contract during which the facility must achieve commercial operation or face the potential of termination of service under the tariff, or termination of the contract.

We also agree with the proposals that termination should not be automatic. Rather, the standard contract should give the utility the opportunity to terminate if project development is not progressing acceptably, and reasonable schedule accommodation cannot be reached. Each tariff/standard contract must provide for notice and the opportunity for parties to address the matter before termination is effective. If unable to reach agreement, however, termination should move forward so the queue may be made available for another project.

3.10.2. Interconnection

Sustainable Conservation and RCM recommended that the tariff or standard contract include provisions that require utilities to respond timely to interconnection requests. In support, they assert that establishing interconnection has been a barrier to project completion for several biogas digester contracts. They claim that it is not uncommon for the utility review process to take up to a year or longer, with deficiencies identified in a piecemeal fashion. Expediting interconnection will help small generators contribute to the grid, according to Sustainable Conservation and RCM. They recommend a schedule wherein such requests would be initially reviewed for completeness within 30 days, the full review would be completed within 60 days, and final approval provided within 30 days of notification that any necessary corrective action was taken.

We agree with Sustainable Conservation and RCM that timely response to an interconnection request is important to prevent interconnection becoming a barrier to project completion. At the same time, we agree with PG&E that yet

another potentially cumbersome process is undesirable. Rather, adequate protocols already exist for interconnection processes, obviating the need to craft another here.

For example, Commission-approved Rule 21 already provides orderly and timely interconnection procedures and processes. It establishes a timeframe not unlike that suggested by Sustainable Conservation and RCM.[37] Other interconnection situations are addressed by an FERC-approved small generator interconnection procedure (SGIP). The SGIP includes a fast track process for small generators (e.g., less than 2 MW), with timeframes not unlike those recommended by Sustainable Conservation and RCM. We are not persuaded that anything more is needed at this time. We will reconsider this issue if and when presented with convincing evidence of a problem, a systematic pattern of abuse, or other matter that needs attention at the Commission level.

Rule 21 is in place for PG&E, SCE, SDG&E and BVES. Sierra also has a version of Rule 21 but without the same timeframe provision. We require PacifiCorp, Sierra and MU to follow the same principles of timely review and disposition of interconnection requests as in Rule 21 for other utilities. We do

[37] For example, with certain exceptions, the utility must generally provide interconnection information and documents within three days of a request, and will typically establish an individual representative as a single point of contact. (See Rule 21, § C.1.) Normally within 10 business days of an application, the utility will acknowledge receipt and state whether the application is complete. Initial review will be completed within 10 business days of receipt of a complete application. If the initial review determines the proposed facility can interconnect by means of a simplified interconnection, that agreement is provided to applicant for signature. If not, a supplemental review is undertaken, to be completed within 20 days. The process is subject to a specific and defined dispute resolution procedure, and review by the Commission. (See Rule 21, § G.)

this without requiring that they file either their own version of Rule 21, amend then current rules, or file another interconnection protocol. We will enforce the requirement of timely review and disposition of an interconnection request, however, if a complaint is brought to our attention.

3.11. Payment Provisions

PG&E proposes to pay generators monthly if the value of the purchased energy is greater than $50. If the amount owned by PG&E to the seller is less than $50, PG&E will pay the generator on a quarterly basis. Sustainable Conservation and RCM recommend adoption of PG&E's proposal for processing payments to sellers. We do so with regard to PG&E, but decline to require it for all respondents.

SCE and SDG&E each propose that the utility not make any payment to the generator until the amount is over $1,000, with an annual true up at the end of the calendar year. We are satisfied that SCE and SDG&E have reasonably weighed their administrative costs for making payments when balances as low as $50 are due, while taking customer satisfaction and other factors into account. Moreover, the SCE and SDG&E proposal is in the context of full buy/sell. Full buy/sell will tend to have larger payments than excess sales.

Sustainable Conservation and RCM neither establish a need to determine program details down to this minute a level, nor that sellers are materially dependent upon cash flows payments below $999. Sellers will be paid under all proposals. We encourage SCE and SDG&E to make payments when balances are as low as $50, especially in the context of a seller selecting the 'excess sales' choice, but we do not require it. While program uniformity is generally desirable, the uniformity here is that all sellers are paid on a timely, reasonable basis.

4. Other Customers

We adopt a limited expansion of this basic tariff/standard contract program from water/wastewater customers to other customers. We do this today for only two utilities: SCE and PG&E. We also limit the expanded availability to the same basic terms adopted above for water and wastewater customers (e.g., 1.5 MW or less per project; allocation of 123,884 kW for SCE and 104,603 kW for PG&E, for a combined total of 228,487 kW).

The expanded availability is separate and distinct from the program to implement § 399.20. Therefore, the tariffs/standard contracts should also be separate and distinct.

This will permit clear implementation and administration of the § 399.20 provisions in today's order. These tariffs/standard contracts will establish that certain availabilities are for the § 399.20 program, are up to a 250 MW limit (prorated per utility), are for water and wastewater customers, and are subject to the terms and conditions therein.

Separate tariffs/standard contracts will keep the further availability distinct. It will make clear that the separate tariffs/standard contracts are for other customers who seek to sell electricity generated by renewable resources from projects of 1.5 MW or less, are available up to a combined total of 228.4 MW, along with any other terms and conditions that apply.

4.1. Background

Section 399.20 applies to public water and wastewater agencies. It adopts a definition of "electric generation facility" specific to those agencies. It does not exclude application of the concept to a broader group of customers. Nor does it prohibit employing the same or similar definition of generation facility to this expanded group.

The model for standardization, efficiency, simplicity and transparency framed in § 399.20 appears to be a useful model for other customers. Other customer groups have expressed interest in a standardized tariff or contract.[38] We have said that it may make sense to look at standard contracts for relatively small generators using renewable fuels, including bio-energy.[39]

The CEC recommends further analysis of using feed-in tariffs to spur additional renewable resource development.[40] The water and wastewater tariff here is a form of feed-in tariff. It is worthy of further assessment to promote reasonable additional renewable resource development.

It might also be reasonable to employ tariffs/standard contracts in some situations as part of the Commission's application of standard terms and conditions under the RPS Program. For example, the administrative savings, simplicity and transparency from tariffs/standard contracts may be particularly appropriate for some resources while reasonably satisfying RPS Program goals and objectives.

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[38] Comments of Western United Dairymen and Comments of RCM Digesters in Application 06-10-003.

[39] D.07-03-042.

[40] 2006 Integrated Energy Policy Report (IEPR) Update, January 2007, p. E-7. A feed-in tariff obligates a utility to purchase electricity at a tariff rate set by a regulatory authority. The tariff rate may be set at either a fixed price, or a fixed premium above a benchmark price (e.g., spot market price), and may reflect the duration of the purchase. Price levels and premiums may vary by technology, reflecting variation in technology costs, and may or may not include incentives for some technologies. The incentives, if any, may decrease over time.

Finally, under the Public Utilities Regulatory Policies Act (PURPA), California currently has a "must purchase" obligation for qualifying facilities up to 20 MW.[41] It may be appropriate to fulfill that duty for RPS generators using a tariff/standard contract.

We seek resource programs that are relatively simple, transparent, efficient and cost-effective, while pursuing growth in a LCBF order. A program of tariffs/standard contracts may be particularly appropriate, and satisfy the considerations summarized above.

To explore this opportunity and related issues, the Amended Scoping Memo asked parties to address whether or not the availability of the § 399.20 tariffs and/or standard contracts should be expanded to other customers. In responses, SCE says it does not oppose voluntary expansion conditioned on application of the same provisions outlined in § 399.20 (e.g., eligible renewable energy resource within the meaning of § 399.12; a retail customer of SCE; interconnected and operated in parallel with the utility system; full buy/sell; 1.5 MW or less; proportionate allocation of 250 MW obligation).

PG&E reports that it developed a version of the § 399.20 power purchase agreement prior to enactment of § 399.20. PG&E says its § 399.20 proposal may be adapted to be available to entities other than public water and wastewater facilities, and that it is prepared to offer what it would call a "Small Renewables

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[41] FERC Order 688 (October 20, 2006), *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*; 18 C.F.R. § 292, 71 Red. Reg. 64342 (December 1, 2006); see Proposed Decision of ALJ Halligan filed April 24, 2007 in R.04-04-003, pp. 18-20.

Generator PPA [Purchase Power Agreement]" to certain sellers of renewable energy.

Other respondents generally oppose expansion. PacifiCorp says, for example:

> "PacifiCorp engages in several contracts with qualified facilities pursuant to PURPA mandates. These contracts have standard terms and conditions and provide an efficient and effective means for promoting and procuring renewable resources. As a result, the expansion of this standard tariff to other customers may be unnecessary, since it duplicates PURPA's long-standing mission to promote the development of alternative resources." (April 11, 2007 Proposal, p. 7.)[42]

CEERT supports additional study. DRA, Sustainable Conservation and RCM support expansion without additional delay.

4.2. Expansion for SCE and PG&E

4.2.1. Limited Expansion

We adopt the proposals of SCE and PG&E identified above to initiate limited expansion to other customers of the tariffs/standard contracts here, pending further consideration as discussed below. The expanded availability is adopted subject to the same basic terms used for the water/wastewater program.

For example, we adopt a tariff along with a standard contract. We employ the same capacity allocations and limits (e.g., 123.9 MW for SCE, 104.6 MW for

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[42] PacifiCorp clarifies that the standard tariffs to which it refers "concern existing incentive programs, such as net metering and qualifying facility tariffs. The 'standard tariffs' developed in the context of these existing incentive programs demonstrate that additional 'feed in' tariffs to spur renewable development may be unnecessary and duplicative of existing programs that provide similar opportunities for renewable investment." (May 9, 2007 Reply Comments, p. 3.)

PG&E). The capacity allocation may be updated on an as needed basis. The purchase rate is the utility's MPR, without reduction for administrative or other fees. We limit projects to 1.5 MW or less. Participants in this expanded availability are not eligible for SGIP or net metering programs. The standard terms and conditions described above also apply here. The tariff must provide for full buy/sell, with an option for the seller to select sales of excess only. The buyer may elect to terminate the agreement if commercial operation has not commenced within 18 months of the date of the agreement, or if the project makes no sales for a period of 12 consecutive months (subject to a reasonable opportunity for the seller to cure delays or non-operation). SCE and PG&E will keep the Commission informed about the program, including information on projects in the queue, as requested by Energy Division. We direct SCE and PG&E to submit advice letters to accomplish this parallel availability at the same time they file advice letters for water and wastewater public agency customers.

PG&E recommends that it be permitted to terminate the expanded availability five years after it is first authorized by the Commission and implemented by the utility. Alternatively, PG&E says this may be accomplished concurrently with a monitoring program, wherein the utilities may suggest program alterations, including termination in the event of unforeseen problems.

We decline to adopt an automatic sunset for the expanded availability. The 228.4 MW limit is an adequate limit and constraint. As explained with the water and wastewater program above, the tariff is closed to new customers when the allocation is met. Respondents are not required to sign new agreements for capacity beyond their allocation (but will keep a "queue" for other interested developers and projects).

The capacity allocation will mitigate problems should there be an excessive response. It will contain the magnitude of the consequences, if any. It will permit a reasonable opportunity to gain experience without exposing projects, ratepayers, utilities, or the state to unreasonable risks, or unreasonably jeopardizing public health and safety.

We expect respondents to keep the Commission informed about the progress of this program, and respond timely to all requests for information made by the Commission through Energy Division or other staff. At any time, and certainly if unexpected and significant problems arise, respondents and parties may move for program alterations and/or termination. While we think the capacity limit of 228.4 MW provides reasonable protection against uncertainties, parties may move for other protection at any time as needed.

4.2.2. SCE Biomass Standard Contract

We note that SCE has its own Biomass Program with its own standard contracts. SCE's website states that its program offers three biomass standard contracts based on size: projects less than 1 MW, 1 MW to 5 MW and 5 MW to 20 MW. Contract terms are for 10, 15 and 20 years, and SCE seeks to contract up to 250 MW of new biomass capacity through this program. The contracts set the price at SCE's MPR.

We make three observations. First, SCE has not presented its Biomass Program and Biomass Standard Contracts to the Commission. We take no official position on that program or its standard contracts at this time.

Second, our expansion here of 123.8 MW for SCE with regard to other customers is relatively modest compared to SCE's own initiative to secure 250 MW of biomass alone. Third, the adopted expansion here is separate and distinct from SCE's separate biomass expansion. If both are successful, SCE

could acquire 123.8 MW from other (non water/wastewater) customers (but which may include biomass), and 250 MW from biomass, for a total of 373.8 MW. This would be in addition to the 123.8 MW from water/wastewater customers, for a total of 497.5 MW.

4.3. No Expansion to Other Utilities

We decline to expand the program to SDG&E and other utilities for now. SDG&E expresses opposition, preferring to focus its limited resources on projects with more "bang for the buck." For example, SDG&E says the administrative cost of negotiating up to 20-30 contracts each for 750 kW or less (for its allocated share of about 20 MW) at MPR prices would divert attention and resources from contracts with greater procurement amounts at or below MPR.

To the contrary, simplicity and cost-savings are important reasons why the § 399.20 program is by tariff and standard contract. The administrative cost to "negotiate" these purchases is small when done by tariff/standard contract. PG&E notes that this is one advantage of the program, thereby providing "access to sources of supply that cannot or would not otherwise market power."[43]

Nonetheless, we accept the proposition for now that SDG&E and others should focus their attention on larger projects. The entire allocation for these remaining utilities is 21.6 MW. We are satisfied with an initial expansion of 228.4 MW through SCE and PG&E. This will allow respondents and parties to present factual, legal and public policy issues, as necessary or appropriate for our further consideration and decision, as discussed below. It will allow respondent, parties and the Commission to learn from the initial experience.

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[43] April 1, 2007 Proposal, p. 11.

4.4. Net Greenhouse Gas Emissions from Projects Using Biomass Fuels

Sustainable Conservation and RCM ask that the Commission clarify a Commission finding regarding net greenhouse gas (GHG) emissions from biomass, which they say was made in Attachment 7 to D.07-01-039. In particular, they ask that the Commission clarify that farmers do not need to buy additional offsets when selling biogas derived renewable energy.

SCE correctly responds that this is beyond the scope of this proceeding, including the expansion of the availability of the § 399.20 tariff/standard contract to other customers. Sustainable Conservation and RCM may seek clarification in the GHG proceeding.

4.5. Further Process

CEERT and several parties recommend further study before expanding the availability to other customers. CEERT suggests a Commission staff White Paper on feed-in tariffs followed by comments, a workshop, a workshop report, comments on the workshop report, and a draft decision.

We will not here order a particular administrative structure for further study, but leave that up to the assigned Commissioner and/or ALJ. Respondents and parties should present the relevant factual, legal and public policy questions for consideration. SCE and PG&E should provide relevant data and information on experience with the 228.4 MW expansion (including whether the expansion is of great or little interest to the RPS community; whether projects are "in the queue;" and potential program improvements, if any, should the Commission desire to continue or expand the program).

PG&E cautions that the Commission should avoid potential disadvantages of standard offers by authorizing the utilities to employ certain Commission-approved controls on their availability. For example, PG&E says:

> "any standard contact must not be an open-ended obligation like the 'standard offer' contracts made available to Qualifying Facilities (QFs) in the 1980s. As originally conceived, standard offer QF contracts were made available to all qualified sellers, without limitation. Changes in the energy markets not anticipated when the standard offers were developed induced the Commission to suspend the availability of standard offers." (April 11, 2007 Proposal, p. 11.)

We agree with PG&E that neither the water and wastewater program, nor the expanded program, should be "open-ended." The unanticipated "changes in the energy markets" that led to Commission suspension of the standard offers in 1984 (only five years after program adoption) were largely driven by too much success. The problem was overwhelming response with too much potential supply. As said by the Director of the Commission's Policy Division in the 1980s, California suffered an "embarrassment of riches."

One lesson learned from that experience is to adopt certain controls. We do that here by implementing the 250 MW limit for the water and wastewater program, and 228.4 MW for expansion to other customers. This places an automatic "stop" on the program should it become too successful at the then available MPR. At each "stop" point, the Commission has the opportunity, with input from respondents and parties, to determine if the MPR should be adjusted upward or downward for the next increment, whether to implement another increment, the size of that increment, and any other relevant issues.

Thus, among the questions for study may be what Commission-adopted controls and limits should be placed on the program. It might also include what

other modifications are necessary, if any, to more thoroughly implement "feed-in" tariffs.

CEERT and others recommend coordination with the CEC. In particular, CEERT recommends taking advantage of the information gathered at the CEC's May 21, 2007 workshop on feed in tariffs, along with other related progress on those tariffs. We agree. We continue to work collaboratively with the CEC on this program. We will take advantage of workshop results, research and recommendations from the CEC to help meet our RPS and GHG goals, including data on feed-in tariffs. Again, we will leave the actual schedule and issues for further consideration up to the Assigned Commissioner and ALJ, with input from respondents and parties.

5. Implementation

Each respondent must, upon its new tariff/standard contract becoming effective, notify its water, wastewater and, to the extent reasonable, other potentially interested or affected customers of the availability of this new opportunity. In addition, each respondent must include information regarding this tariff/standard contract on its web page.

Among other things, the information on a respondent's web page should make it easy for a prospective customer to see an overview of the terms and conditions of the tariff/standard contract, applicable rates, and amount of unsubscribed allocated capacity. Respondents must keep these items up-to-date (e.g., rates, unsubscribed allocated capacity) so prospective customers have a reasonable opportunity of knowing current conditions and available options.

Respondents should provide the Public Advisor and the Energy Division Director an opportunity to comment on the specifics of the notice and the web

page. Respondents must modify the notice and web page to the extent directed by the Public Advisor and/or Energy Division Director.

6. Avista and New West Energy

Avista Utilities is named as a respondent in the classification of small and multi-jurisdictional utilities. On April 4, 2007, Avista Corporation (Avista) moved to be dismissed as a respondent. No responses were filed. Avista's motion is a final determination of the proceeding relative to Avista. It must be addressed by the Commission, not the Administrative Law Judge. (Rule 9.1 of the Commission's Rules of Practice and Procedure (Rules)). Avista states it has never provided electric service in California, and sold its natural gas distribution properties to Southwest Gas Corporation in 2005. This transfer was approved by the Commission on April 28, 2005. (D.05-03-010.) Avista's motion is granted.

New West Energy (NWE) is named as a respondent in the category of registered electric service provider (ESP). It has come to our attention that this is an error. NWE cancelled its registration as an ESP on February 16, 2006. NWE shall be dismissed as a respondent.

7. Comment Period on Proposed Decision

On June 26, 2007, the proposed decision of ALJ Mattson in this matter was mailed to parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on July 16, 2007 by SCE, SDG&E, PG&E, CEERT and Sustainable Conservation. Reply comments were filed on July 23, 2007 by SCE, Inland Empire Utilities Agency, and jointly by three parties (Sustainable Conservation, California Farm Bureau Federation, and RCM). We have made changes based on comments and reply comments as appropriate.

8. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Anne E. Simon and Burton W. Mattson are the assigned ALJs in this proceeding.

Findings of Fact

1. No motions for evidentiary hearings were filed.

2. Each electrical corporation proposes a tariff to comply with its obligations under § 399.20, and all but Sierra also propose an accompanying standard contract.

3. A "take it or leave it" tariff/standard contract (i.e., one that does not require substantial negotiation between buyer and seller) is consistent with the Commission's fundamental goal here of a simple and streamlined program.

4. Parties agree on a general methodology for allocation of proportionate shares of the 250 MW for this program, and CEC performed the necessary calculation.

5. The approach of performing capacity allocation updates as needed is consistent with the assumption that the capacity allocation will be reasonably stable, and provides cost savings while permitting updates as appropriate.

6. A relatively simple program includes one wherein nearly all important and relevant information may be found in one, or only a few, locations, including the capacity allocation and rates.

7. First-come-first-served applied in the order of when the buyer receives a seller-executed (signed) standard contract (or for Sierra the date of the customer's request for service under the tariff), rather than based on project on-line date, will promote an orderly process, including certainty that the output will be purchased when the project subsequently becomes operational.

8. Once the capacity allocation is met, periodic re-establishment of the queue will foreclose the possibility that sellers remain in the queue indefinitely.

9. Maintenance of the queue by individual project or proposal, without being assignable or tradable, will ensure that the rank within the queue does not itself have a market value.

10. An open-ended or "floating" capacity allocation would introduce confusion and uncertainty in tariff administration, and create risk of more generation being developed than needed or desirable at the MPR.

11. The MPR methodology does not include a provision for reducing the MPR for Scheduling Coordinator services or benefits provided to the seller, and it is not dependent upon the standard terms and conditions.

12. The proposed tariffs and standard contracts do not make clear whether the applicable rate (MPR) applies based on forecast or actual initial operation.

13. Each RPS bid solicitation accepted by the Commission and undertaken by the large investor-owned utilities over the last several years has included payments based on TOU factors, which is consistent with the Commission's intended application of the MPR methodology.

14. A very important aspect of the RPS Program is development, integration and operation of resources on an LCBF basis, and TOU factors do a better job than do annual average rates of promoting LCBF development, integration and operation.

15. An annual average rate would require ratepayers of PG&E and SCE to buy electricity during the off-peak period at a price above the TOU-based off-peak price, thereby incurring unreasonable remarketing costs and frustrating efficiency, equity and LCBF goals.

16. This program has elements which overlap with the SGIP and net metering programs.

17. Not all Commission-adopted STCs apply here (e.g., performance standards since this is a pay for performance program), others apply as adopted by the Commission (e.g., Green Attributes as corrected by D.07-05-057 to ensure buyer and sellers are trading the same item), and others may apply with simplified wording to accomplish the same objective (e.g., confidentiality).

18. Providing an opportunity for both full buy/sell and excess sales will permit gathering important information regarding the economics of, and market response to, the two approaches.

19. Sellers have reduced incentive to enter into contracts for the sale of their generation at a market rate if then required to buy back that same generation to serve their own on-site needs at a much higher retail rate.

20. The seller's decision on how small or large to make the generation facility may be influenced, if not driven, by the choice of full buy/sell or excess sales.

21. A fixed time period leading to potential termination of service under the tariff, or termination of the contract, presents an orderly process for both developer and utility in which to frame future events and plans, and it opens the queue to other projects if and when a project in the queue is subject to termination for not progressing reasonably toward completion or not continuing to operate reasonably.

22. Timely response to an interconnection request is important to prevent interconnection becoming a barrier to project completion, and FERC-approved SGIP and Commission-approved Rule 21 provide orderly and timely interconnection procedures and processes.

23. The model for standardization, efficiency, simplicity and transparency framed in § 399.20 is a useful model for other customers.

24. Other customer groups have expressed interest in a standardized tariff or contract.

25. The Commission has expressed interest in considering standard contracts for relatively small generators using renewable fuels, including bio-energy.

26. The CEC recommends further analysis of using feed-in tariffs to spur additional renewable resource development.

27. The water and wastewater tariff here is a form of feed-in tariff.

28. One application of standard terms and conditions under the RPS Program is reasonable use of tariffs/standard contracts in some situations.

29. California currently has a must purchase obligation for QFs up to 20 MW pursuant to PURPA, and one way to fulfill that duty for RPS generators is by a tariff/standard contract.

30. The fixed capacity allocation of 228.4 MW for expansion of the program to other (non-water/wastewater) customers will, by containing the magnitude of the consequences, if any, mitigate problems should there be an excessive response.

31. Sustainable Conservation and RCM's request that the Commission clarify a finding regarding net greenhouse gas (GHG) emissions from biomass (made in Attachment 7 to D.07-01-039) is beyond the scope of this proceeding.

32. Avista has never provided electric service in California, Avista sold its gas distribution properties to Southwest Gas Corporation in 2005, and NWE cancelled its ESP registration in February 2006.

Conclusions of Law

1. The cost of power procured by an electrical corporation through the tariffs/standard contracts authorized by this order is per se reasonable, in the public interest, and recoverable in rates over the life of the contract, subject to Commission review of contract administration by the electrical corporation.

2. All procurement pursuant to the tariffs/standard contracts authorized by this order is procurement from an eligible renewable energy resource from purposes of determining an electrical corporation's compliance with an obligation that it may have to procure eligible renewable resources pursuant to the California Renewables Portfolio Standard (Pub. Util. Code § 399.11 et seq.), Decision 03-06-071, or other applicable law.

3. Sierra's proposed use of only a tariff should be approved, and other respondents' proposed use of a tariff in concert with a standard contract should be approved.

4. Other than the seller selecting limited items within the contract (e.g., contract term, full buy/sell or excess sales), the standard contracts should be "take it or leave it" (i.e., not require seller to engage in substantial negotiation to complete the transaction).

5. The recommended allocation of shares of the 250 MW for this program should be adopted.

6. Capacity allocation should be updated only as needed and appropriate.

7. The capacity allocation should be stated in the tariff.

8. First-come-first-served should be applied on the basis of the date the buyer receives the standard contract executed (signed) by the seller (for Sierra, the date the customer requests service under the tariff) with a specific subsequent period of time allowed for the project to come on-line, subject to the buyer electing to

terminate the contract (or terminate service under the tariff) if seller is not reasonably continuing project development.

9. The queue should periodically be re-established, as needed, after the initial capacity allocation is fully subscribed, and should be maintained in a manner such that ranking within the queue does not itself create a market value.

10. BVES should be permitted to flexibly employ its capacity allocation to encourage additional renewable resource additions, but this should not be permitted for other utilities.

11. Respondents should provide timely information on this program when required by the Commission.

12. PacifiCorp should be permitted to include rates in its tariff, Sierra should be required to include rates in its tariff (because it does not propose a standard contract), and other respondents should be required to include rates in their standard contracts.

13. Respondents should each use the uniform statewide MPR, unless and until a different MPR is found reasonable for SMJUs.

14. PG&E's tariff/standard contract should not contain the provision that the rate "shall be reduced by a ten (10) percent administrative fee."

15. The tariff/standard contract should specify that the applicable table of rates is determined by the date of contract execution, while the applicable rate (MPR) within the table is based on actual commercial operation, not the commercial operation date initially forecast or expected when the standard contract was signed.

16. The MPR-based rate should be time differentiated, not an annual average, except for Sierra, BVES and MU (if MU so chooses).

17. The tariff for SCE, PG&E and SDG&E should provide for service from projects with an effective capacity of not more than 1.5 MW, while the tariff for PacifiCorp, Sierra, BVES and MU may provide for similar service from projects of not more than 1.0 MW.

18. Authorized tariffs/standard contracts should make clear that participants may not simultaneously obtain benefits from both this tariff and the SGIP, net metering programs, California Solar Initiative, or other similar program.

19. Some STCs should be incorporated into the tariffs/standard contracts exactly as worded by the Commission, others may be simplified, and others need not be used, as explained in the body of this order.

20. The law as read by SCE and SDG&E regarding full buy/sell, or PG&E regarding excess sales, are each a reasonable interpretation of the statute.

21. The seller should have the option under the tariff/standard contract to select either full buy/sell or excess sales in the service areas of SCE, PG&E and SDG&E.

22. Each respondent should include a period of (a) 18 months in its tariff or standard contract during which the facility must achieve commercial operation or face the potential for termination of service under the tariff or the standard contract, and (b) no more than 12 consecutive months during which the project may not make any sales or face the potential of termination or service under the tariff or the standard contract.

23. The principles of orderly and timely interconnection procedures and processes in Rule 21 (for SCE, PG&E, SDG&E and BVES) should be required of PacifiCorp, Sierra, and MU (even if they are not required to file their own version of Rule 21, amend their current rules or file another interconnection protocol) and the Commission should enforce the requirement of timely review and

disposition of an interconnection request if a complaint is brought to the Commission's attention.

24. A limited expansion of the basic tariff/standard contract program framed in § 399.20 should be adopted for customers other than water/wastewater agencies in the service areas of SCE and PG&E.

25. The program as expanded to other than water/wastewater customers should be limited to 228.4 MW and should use the same essential features as adopted for the § 399.20 tariffs/standard contracts, such as but not limited to: (a) projects no larger than 1.5 MW, (b) tariff rate is the MPR, (c) maximum capacity allocated to SCE and PG&E as in the § 399.20 program (i.e., SCE allocated 123.8 MW, PG&E allocated 104.6 MW), (d) participants not eligible for SGIP or net metering, (e) seller has option for full buy/sell or excess sales, and (f) buyer may terminate agreement if commercial operation not commenced within 18 months or fails to operate for a period of 12 consecutive months.

26. Each respondent should, upon the new tariff/standard contract becoming effective, notify its water, wastewater and, to the extent reasonable, other potentially interested or affected customers of the availability of this new opportunity, and maintains current information about this opportunity on its web page.

27. Avista and NWE should be dismissed as respondents in this proceeding.

28. This order should be effective today so that tariffs/standard contracts may be filed and become effective without delay, thereby helping California meet its goal of having 20% of its electricity generated by RPS-eligible facilities by 2010.

ORDER

IT IS ORDERED that:

1. Within seven days of the date this order is mailed, each electrical corporation named below shall file and serve an advice letter. The electrical corporations are: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company, PacifiCorp, Sierra Pacific Power Company (Sierra), Bear Valley Electric Service Division of Golden State Water Company, and Mountain Utilities. The advice letter shall transmit a tariff and (except for Sierra) a standard contract to implement the provisions of Pub. Util. Code § 399.20 (RPS Tariff for Water/Wastewater Customers). The tariff and standard contract shall be consistent with the proposal each electrical corporation filed in this proceeding, but shall be revised and amended consistent with the discussion in the body of this order, findings of fact and conclusions of law. The revisions and amendments are summarized in Attachment A. The advice letter, tariff and standard contract shall be in compliance with General Order 96-B. The advice letter may be filed pursuant to the provisions of either Tier 1 or Tier 2.

2. Within seven days of the date this order is mailed, SCE and PG&E shall each file an advice letter. The advice letter shall transmit a tariff and standard contract for a limited expansion of the program adopted in Ordering Paragraph 1 above pursuant to Pub. Util. Code § 399.20. The expansion shall be to customers other than water/wastewater customers (RPS Tariff for Customers Other Than Water/Wastewater). The tariff and standard contract shall be consistent with the proposal each electrical corporation filed in this proceeding, but shall be revised and amended consistent with the discussion in the body of this order, findings of fact and conclusions of law. The revisions and

amendments are summarized in Attachment A. The advice letter, tariff and standard contract shall be separate and distinct from the advice letter, tariff and standard contract filed pursuant to Ordering Paragraph 1. The advice letter, tariff and standard contract shall be in compliance with General Order 96-B. The advice letter may be filed pursuant to the provisions of either Tier 1 or Tier 2.

3. Each electrical corporation named above shall provide information on these tariffs, standard contracts and programs as and when required by the Commission. This shall include, but is not limited to, data on service under the tariffs, sellers, projects, capacity allocations and project queue. Electrical corporations shall work with Commission staff to develop a reasonable method of periodic reporting of this routine information, if and as determined necessary by Commission staff.

4. Each electrical corporation named in Ordering Paragraph 1 shall, upon the new tariff/standard contract becoming effective, notify its water, wastewater and, to the extent reasonable, other potentially interested or affected customers of the availability of this new opportunity, and maintain current information about this opportunity on its web page. Each electrical corporation shall provide the Commission's Public Advisor and the Energy Division Director an opportunity to comment on the specifics of the notice and web page. Respondents shall modify the notice and web page to the extent directed by the Public Advisor and/or Energy Division Director.

5. Avista Utilities and New West Energy are dismissed as respondents in this proceeding.

6. Rulemaking 06-05-027 remains open.

This order is effective today.

Dated July 26, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

ATTACHMENT A

SUMMARY OF MAJOR CHANGES TO PROPOSED TARIFFS AND STANDARD CONTRACTS

The Commission approves each respondent's proposed tariff and standard contract subject to the specific clarifications, modifications and amendments stated in the order. These items are summarized, but not necessarily limited to, the following. Any conflicts with the order itself are resolved in favor of the order, findings of fact, conclusions of law and ordering paragraphs.

1. **Allocated Capacity Share**: Each respondent's allocated share of capacity will be stated in its tariff to a level of accuracy of one kilowatt.

2. **Rates:** The rate is the market price as determined by the Commission.

   a. Each respondent will include the applicable rate in (i) its tariff (Sierra and PacifiCorp) or (ii) the standard contract portion of its combined tariff/standard contract.

   b. Respondents will use the uniform statewide MPR unless and until a different result is reached for SMJUs in R.06-02-012.

   c. The rate will not be reduced for administrative or other fees.

3. **Actual Commercial Operation**: The tariff/standard contract will specify that the applicable MPR table is the one in effect on the date the contract is signed, and the applicable MPR rate within the table is based on the date of actual commercial operation.

4. **TOU or Annual Average MPR**: SCE, PG&E, SDG&E and PacifiCorp will use time of use (TOU) factors in tariffs/standards contracts for calculating compensation; Sierra, BVES and MU may use an annual average rate.

5. **MW Capacity:**

   a. SCE, PG&E and SDG&E will offer their tariff/standard contract to projects with an effective capacity of not more than 1.5 MW.

b. PacifiCorp, Sierra, BVES and MU may offer their tariff/standard contract to projects with an effective capacity of not more than 1.0 MW.

6. **SGIP and Net Metering**: Participants may not simultaneously obtain benefits from both the § 399.20 tariffs/standard contracts and the SGIP, the net metering programs, California Solar Initiative, or other similar programs.

7. **Standard Terms and Conditions:**

   a**. Green Attributes:** The Commission's exact language shall be used, as stated in D.07-02-011 and corrected in D.07-05-057.

   b. **Eligibility**: The language of PG&E and other utilities is adopted on the basis that it is materially the same as the Commission's STC; the proposal of SCE and SDG&E is adopted for their Appendix C, but they must bring Appendix D into conformance with the Commission's requirement that the output qualifies under the California RPS Program.

   c. **Assignment**: Proposed language is adopted on the basis that it is materially the same (or more restrictive) than the Commission's STC; Sierra need not have this term since its service is provided by tariff.

   d. **Applicable Law**: The proposed language of PG&E, SCE, SDG&E, PacifiCorp and BVES is adopted for the first sentence; the proposed language of PG&E is adopted for the second sentence, and will also be used by SCE, SDG&E, PacifiCorp and BVES; the proposal of Sierra that there be no similar first sentence is adopted, but Sierra must include the second sentence as proposed by PG&E.

   e. **Confidentiality**: All proposals are adopted; in addition, all utilities shall include the term proposed by SCE, SDG&E and BVES regarding release of certain information to CEC and the Commission.

f. **Contract Term**: The proposals are each adopted, and respondents are encouraged (not required) to be open to opportunities for other contract durations.

g. **Non-Performance**: The proposals are adopted; in addition, each respondent shall include the term proposed by PG&E that buyer is entitled (not required) to terminate the agreement if seller has not sold or delivered energy to buyer for a period of 12 consecutive months.

h. **Contract Modification**: Proposals are adopted.

8. **Full Buy/Sell or Excess Sales**: SCE, PG&E and SDG&E shall offer the customer the choice of either full buy/sell or excess sales, to be selected by the customer. Other utilities shall offer full buy/sell, and may offer an excess sales option to be selected by the customer.

9. **Initial Operation:** Each respondent's tariff/standard contract will grant buyer the right to terminate the service if seller has not achieved commercial operation in 18 months from execution date. The seller shall be given reasonable notice and opportunity to address concerns before termination is effective.

10. **Interconnection:** Respondents shall follow their FERC-approved SGIP, or Commission-approved Rule 21, as appropriate and applicable for each particular situation regarding an interconnection agreement; in all cases, respondents shall respond to an interconnection request on a timely basis and without unreasonable delay; PacifiCorp, Sierra and MU will employ similar principles of timely review and disposition of interconnection requests as in Rule 21 of other utilities.

11. **Expanded Availability:** SCE and PG&E shall file advice letters with tariffs/standard contracts for the purchase of electricity generated by renewable resources from customers other than water and wastewater, using the same basic terms and conditions as adopted for water/wastewater customers.

(END OF ATTACHMENT A)